

Appendix A.

Transocean Deepwater Horizon Rig Incident Investigation Into the Facts and Causation (April 23, 2010)

The President of BP Exploration & Production Inc. agreed the following Terms of Reference and has requested that Mark Bly, Group Head of Safety & Operations, lead the investigation team¹:

The scope of the investigation to find the facts surrounding the uncontrolled release of hydrocarbons and efforts to contain the release aboard the Transocean drillship Deepwater Horizon, located approximately 40 miles south of Venice, LA at Mississippi Canyon 252, BP's Macondo prospect is as follows:

1. Collect evidence surrounding the incident²
2. Determine the actual physical conditions, controls, and operational regime related to the incident to understand:
 - a. Sequence of relevant events
 - b. Reasons for initial release
 - c. Reasons for fire
 - d. Efforts to control flow at initial event
3. Prepare a report to include:
 - a. Background
 - b. Timeline
 - c. Description of incident
 - d. Critical factors
 - i. Immediate Causes
 - ii. System Causes
 - e. Proposed Recommendations
4. Administrative
 - a. All activities of the fact-finding teams will be approved in advance by the respective team leader
 - b. Retain all incident investigation team documents (including notes, drafts, electronic documents and emails) relating to the fact-finding and the incident
 - c. Maintain confidentiality of our discussions
 - d. BP person at each interview
 - e. No questions or tasks to BP contractors without BP approval

¹ James Lucari, Managing Attorney – BP Legal HSSE and Regulation, has been assigned to provide legal advice and counsel to Mr. Bly in his role as investigation team lead.

² Given the business and regulatory relationships involved in this context, the Incident Investigation team's efforts will be informed by physical evidence, data and information that is in the custody and/or control of third parties. The incident investigation team's access to this information may affect its ability to complete the terms of reference set forth herein.

Appendix B. Acronyms, Abbreviations and Company Names

Term	Descriptions
~	approximately
' or ft.	foot
" or in.	inch
#	number
%	percent
Ah	ampere hours
AMF	automatic mode function
Anadarko	Anadarko Petroleum Corporation
APB	annular pressure build-up
APD	Application for Permit to Drill
API	American Petroleum Institute
APM	Application for Permit to Modify
bbl	barrel (1 bbl = 42 US gal)
bbls	barrels
BOEMRE	Bureau of Ocean Energy Management, Regulation and Enforcement
BOP	blowout preventer
BP	BP Exploration & Production Inc.
bpm	barrels per minute
BSR	blind shear rams
°C	degree(s) Celsius
Cameron	Cameron International Corporation
cap	lead cement
CBL	cement bond log
cc	cubic centimeters
CCTV	closed circuit television
C/E	cause and effect

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Term	Descriptions
CFD	computational fluid dynamics
CFR	Code of Federal Regulations [e.g., for offshore drilling in U.S. waters]
CGD	combustible gas detector
chk/kill	choke and kill
CPU	central processing unit
CSI	CSI Technologies, Inc.
CSR	casing shear ram
CVP	conduit valve package
Damon Bankston	Damon B. Bankston, a marine supply vessel
D&C	Drilling and Completions
DH-MW	downhole mud weight
DPO	dynamic positioning officer
Dril-Quip	Dril-Quip, Inc.
DWOP	Drilling and Well Operations Practice
EB	Cameron Engineering Bulletin
ECD	equivalent circulating density
EDS	emergency disconnect sequence
ETP	Engineering Technical Practice
°F	degree(s) Fahrenheit
FEA	finite element analysis
F&G	fire and gas
FI	flow indicator
FIT	formation integrity test
f-kp	feet per thousand pounds (feet-1000/lbs)
FMECA	failure mode effects and criticality assessment
fph	feet per hour
ft.	feet
ft ²	square feet
gal	gallons (U.S.)

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Term	Descriptions
gal/hr	gallons per hour
gal/sack	gallons per sack
GoM	Gulf of Mexico
gpm	gallons per minute
H ₂ S	hydrogen sulfide
Halliburton	Halliburton Company
HAZOP	hazard and operability
hot stab	hydraulic access receptacle for ROVs
HPU	hydraulic power unit
HVAC	heating, ventilation and air conditioning
IADC	International Association of Drilling Contractors
IBOP	internal blowout preventer
ID	inner diameter
IMT	incident management team
in.	inch
K	thousand
KCl	potassium chloride
klb	thousand pounds
ksi	thousand pounds per square inch
lb	pound
lbs	pounds
lb/bbl	pounds per barrel
lb/sack	pounds per sack
lbm/sack	pounds mass per sack
LEL	lower explosive limit
LMRP	lower marine riser package
LOT	leak off test
m	meters
M56	Miocene 56

(continued)

Term	Descriptions
MBI	Marine Board of Investigation
MC 252	Mississippi Canyon Block 252
MD	measured depth
MDT	Schlumberger Modular Formation Dynamics Tester logging tool
MGS	mud gas separator
min	minute
M-I SWACO	M-I SWACO Corporation
MMS	Minerals Management Service
mmscfd	million standard cubic feet per day
MOC	management of change
MOEX Offshore	MOEX Offshore 2007 LLC, a subsidiary of MOEX USA Corporation
MOM	Marine Operations Manual
mud	drilling fluid used in hydrocarbon drilling operations; can be water-based, oil-based or synthetic-based drilling fluids
MUX	multiplex
M/V	marine vessel
MVD	measured vertical depth
NACE	National Association of Corrosion Engineers
NDE	non-destructive examination
NM	Newton meters
No.	number
Oceaneering	Oceaneering International, Inc.
OD	outer diameter
OEM	original equipment manufacturer
Oil States	Oil States Industries, Inc.
OLGA [®]	multiphase flow simulator
OMS	operating management system
OpenWells [®]	<i>OpenWells® Drilling Morning Report</i> ; BP's daily reporting system

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Term	Descriptions
OptiCem™	Halliburton cement modeling tool
P _H	hydrostatic pressure
P&ID	pipng and instrumentation diagram
PI	pressure indicator
PLC	programmable logic controller
pod	subsea control module
PP	pore pressure
ppf	pounds per foot
ppg	pounds per gallon
PRV	pressure relief valve
P _s	shear pressure
psi	pounds per square inch
psig	pounds per square inch gauge
P _w	wellbore pressure
RMS	Transocean's maintenance management system
ROV	remotely operated vehicle
RP	American Petroleum Institute Recommended Practice
rpm	rotations per minute
S-135	drill pipe yield designation Grade S 135,000 psi yield strength material
sec	seconds
SEM	subsea electronics module
SETA	segment engineering technical authority
SOBM	synthetic oil-based mud
Sperry-Sun	Sperry Drilling Services, a Halliburton company
spm	strokes per minute
SPP	standpipe pressure
stb/min	stock tank barrels per minute
stks	strokes (on mud pump)

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Term	Descriptions
TA	technical authority
TCP	toolpusher's control panel
TD	total depth
TOC	top of cement
TOL	top of liner
Transocean	Transocean Ltd.
TVD	total vertical depth
UEL	upper explosive limit
V	volt
VBR	variable bore ram
Vetco	Vetco Gray Inc.
WD	water depth
Weatherford	Weatherford International, Ltd

Appendix F. Roles and Responsibilities for Macondo Well

Major Parties Involved

Deepwater drilling programs are large, complex ventures that require the involvement of several organizations. This appendix provides an overview of the roles and responsibilities of the following entities involved in the Macondo well project. (Refer to *Appendix B. Acronyms, Abbreviations and Company Names.*)

Minerals Management Service (MMS)

MMS had regulatory oversight for offshore oil and gas leasing activities on the outer continental shelf, including the area of the Macondo well. Federal regulations set forth the MMS program for regulatory oversight of offshore operations and governed the process for review and approval of design, drilling operations and rig maintenance plans. An exploration plan was submitted for approval to the MMS before exploratory drilling began on the Mississippi Canyon Block 252 lease. An *Application for Permit to Drill* (APD) was also submitted for approval before drilling began on the Macondo well. Subsequent *Applications for Permit to Modify* (APM) were submitted for approval based on the actual conditions encountered while drilling the well. MMS inspectors visited the rig during drilling operations to monitor compliance with regulations, permits and statutes.

Since June 18, 2010, the MMS's regulatory role has been exercised by the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE).

BP

As the lease operator, BP was responsible for geologic assessment of subsurface formation, engineering design of the well and obtaining regulatory approvals required for construction of the well. BP was also responsible for retaining and overseeing the contractors who supported well design and various aspects of the drilling operations. During drilling operations, BP had staff on the rig who represented the company's interests in operations related to the well; this did not include operations related to non-well-related activities such as rig maintenance or marine systems.

BP retained contractors to provide engineering and operations services, drilling equipment and personnel. These contractors typically operated under their own management systems, supplying their own (or sub-contracted) personnel, equipment and materials as needed. Contracts issued by BP generally covered multi-year terms.

Transocean

Transocean provided the drilling rig, *Deepwater Horizon*, and the personnel to operate it. Transocean was solely responsible for operation of the drilling rig and for operations safety. It was required to maintain well control equipment and use all reasonable means to control and prevent fire and blowouts. Transocean provided, maintained and operated a range of subsea equipment, including the Cameron blowout preventer (BOP) and associated control systems. BP retained the right of inspection and approval of the work performed on its behalf, although the actual performance and supervision of the work was Transocean's responsibility.

Halliburton

Halliburton provided engineering services, materials, testing, mixing and pumping for cementing operations. This included both onshore engineering support and offshore equipment and personnel based on *Deepwater Horizon*. Halliburton was responsible for and provided technical advice as to the design, modeling, placement and testing of the cement that was pumped into place behind the casing string and in the shoe track to isolate the hydrocarbon zone(s) from the wellbore at the Macondo well site.

Sperry-Sun is a Halliburton company that was responsible for mudlogging equipment (including downhole drilling tools) and personnel. Sperry-Sun mudlogging personnel were responsible for monitoring the well and advising the driller in the areas of mud pit volume changes, mud flow in and out of the well, mud gas levels and any pressure fluctuations.

M-I SWACO

M-I SWACO provided mud products, engineering services and mud supervisory personnel. M-I SWACO was responsible for specifying the mud additives to be mixed, measuring mud properties and submitting daily reports to BP regarding mud conditions and effectiveness. At the well site, the Transocean deck and drill crews conducted mud handling at the direction of M-I SWACO's mud engineers.

Weatherford

Weatherford provided the casing components including the float collar, shoe and centralizers. Weatherford also provided the personnel and equipment for running the casing and casing components into the wellbore.

Dril-Quip

Dril-Quip provided wellhead equipment, including the casing hangers, seal assembly and lockdown sleeve used on the Macondo well. Dril-Quip also provided personnel responsible for supervising the installation of this equipment and any subsequent servicing, modifications and maintenance to the wellhead equipment.

Oceaneering

Oceaneering provided remote operated vehicle (ROV) equipment and personnel. Oceaneering had responsibility for transporting, piloting and maintaining the ROV assigned to the Macondo well. Oceaneering used the ROV to inspect the wellhead, BOP stack, riser and seafloor.

Appendix G. Analysis Determining the Likely Source of In-flow

This appendix describes how the hydrostatic pressure observations, OLGA® well flow modeling results and static well kill results support the report's conclusion that the in-flow was from the formation, through the annulus cement barrier, through the shoe track barriers and into the production casing. *Analysis 5A. Well Integrity Was Not Established or Failed* of this report refers to other considerations on which the conclusion was also based—those other considerations are not discussed in this appendix.

The investigation team reviewed real-time surface and subsurface data, witness accounts and modeling results to determine the most likely route of in-flow to the well.

Two barrier failure scenarios were considered:

- Flow through the casing hanger seal assembly in the wellhead.
- Flow through the shoe track barriers (shoe track cement and double-valve float collar).

The possibility of hydrocarbon ingress through the production casing was a third scenario considered in *Analysis 5A*, but as explained there, a design and installation review of the 9 7/8 x 7 in. casing was completed by the investigation team, and no integrity issues were identified. Furthermore, the positive-pressure test completed following the casing installation confirmed the integrity of the production casing.

Engineering analyses were conducted for the casing hanger seal assembly and the shoe track barriers. Although analysis indicated that casing hanger seal assembly failure was not likely, this flow path scenario is included in the hydrostatic pressure and well modeling analyses to further explain why this scenario was determined not to be credible.

The investigation team conducted hydrostatic pressure calculations to match the 1,400 psi pressure observed during the negative-pressure test and performed dynamic flow modeling (OLGA®) to match pressure responses observed prior to the explosion.

This discussion addresses the following topics:

- The Hydrostatic Pressure Effect – a brief review of how pressure changes as fluid moves through the wellbore.
- Changing Cross-section Across the Riser and Production Casing Annulus – an illustration of the changes in system pressure created as fluids flow through the wellbore.
- Hydrostatic Pressure Calculations – an analysis of known reservoir and surface pressure measurements relevant to determining flow path.
- Dynamic Modeling of Drill Pipe Pressure Response – simulations of the two scenarios considered and their conformance with known data.

The Hydrostatic Pressure Effect

Hydrostatic pressure is the pressure exerted by a fluid due to the force of gravity. As shown in *Figure 1*, pressure at any point in a fluid column is generated by the height of liquid above that point. The pressure is calculated as follows:

$$\text{Pressure} = \text{fluid density} \times \text{fluid height} \times \text{gravity}.$$

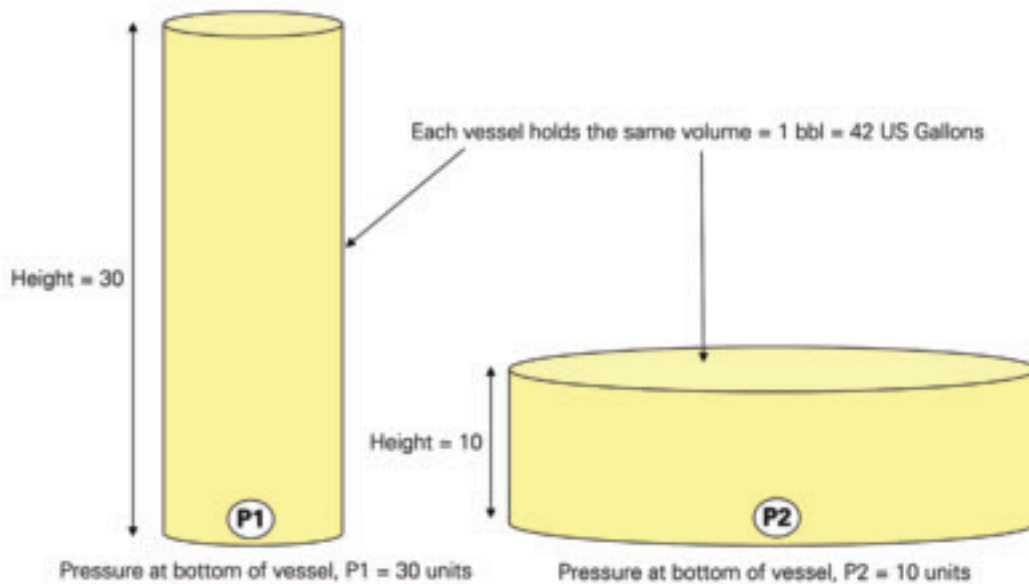


Figure 1. Schematic of How the Same Volume of Fluid Can Create Different Pressures.

As shown in *Figure 2*, a fluid with a higher density (heavier fluid) generates more pressure than a lighter fluid if they are in cylinders of the same height.

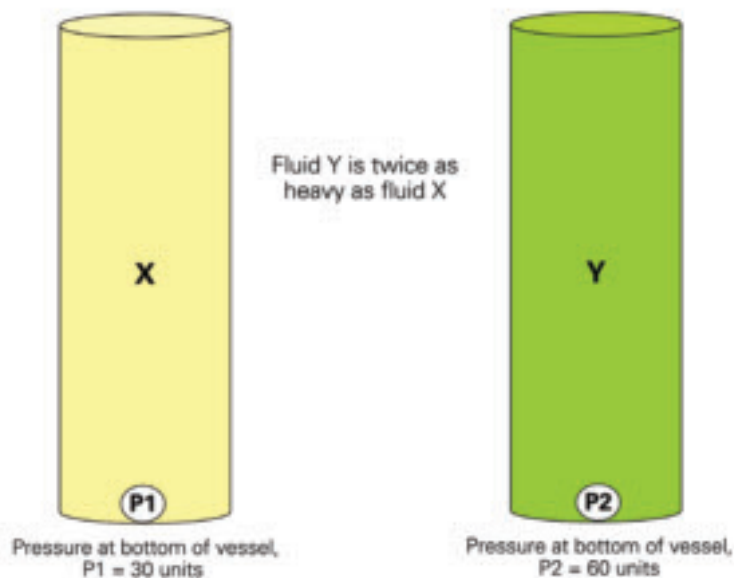


Figure 2. Schematic of How Different Density Fluids Can Create Different Pressures.

Figure 3 shows that when two different fluid columns of the same height are connected, the heavier fluid will transmit pressure to the lighter fluid. If the lighter fluid is trapped at the top, it will generate pressure, which is labeled as P1 in Figure 3.

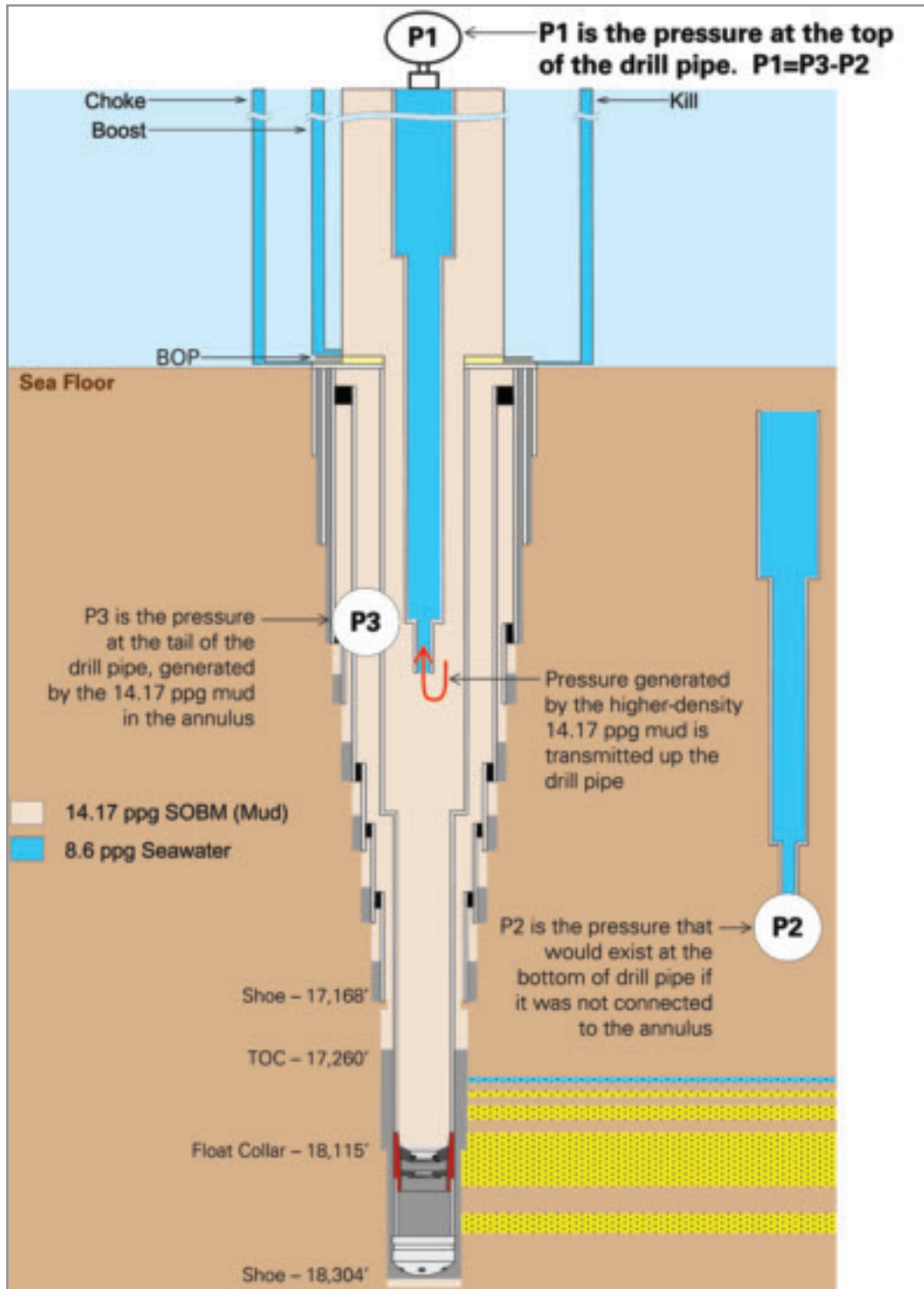


Figure 3. Pressure Transmission Through Connected Fluid Columns.

Changing Cross-section Across the Riser and Production Casing Annulus

Figure 4 shows selected cross-sections through the length of the Macondo well. (The well intervals shown are for illustrative purposes. For well design, refer to *Appendix C. Macondo Well Components of Interest*.) The annular space between the drill pipe and the production casing and between the drill pipe and the riser is the focus of the analysis conducted in the next section of this appendix. The different cross-sections in this region each generate a different hydrostatic pressure for a barrel of fluid occupying that space, as follows:

- Each barrel of fluid (assuming the same fluid) in the annular space between the 3 1/2 in. drill pipe and the production casing would generate approximately 5.6 times more hydrostatic pressure than a barrel of fluid in the riser annulus.
- Each barrel of fluid (assuming the same fluid) in the annular space between the 5 1/2 in. drill pipe and the production casing would generate approximately eight times more hydrostatic pressure than a barrel of fluid in the riser annulus.

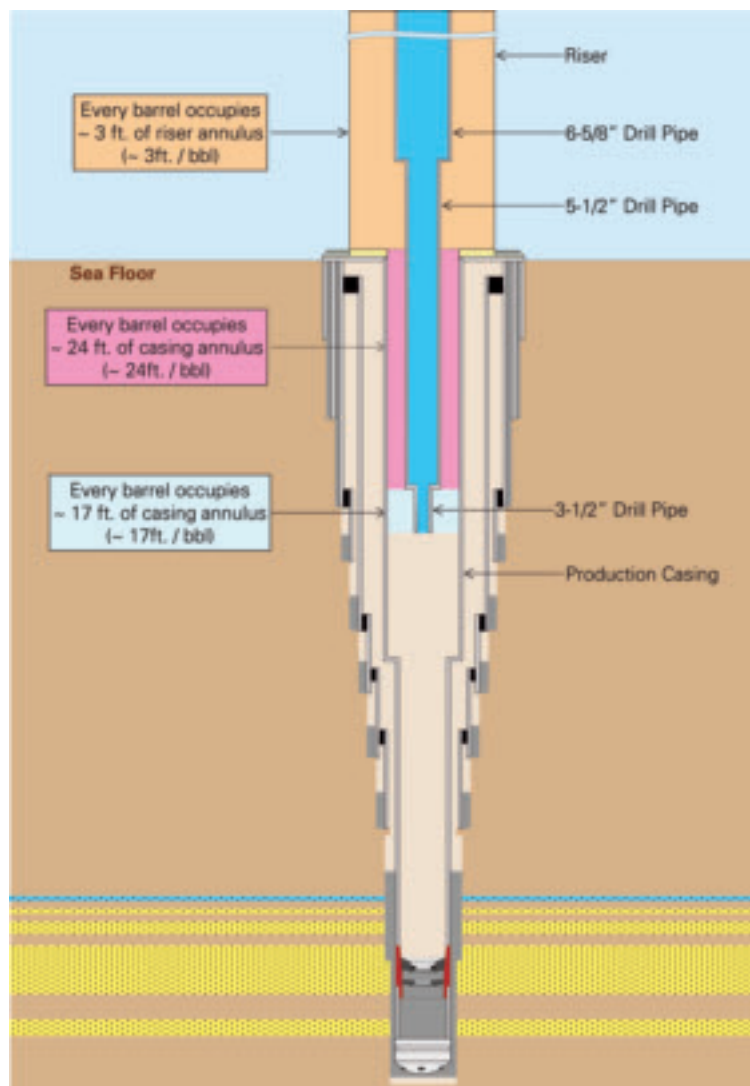


Figure 4. Cross-sectional Area Effect.

Hydrostatic Pressure Calculations

While the negative-pressure test was being conducted on the kill line, a pressure of 1,400 psi on the drill pipe was observed by the rig team. The 1,400 psi observation was confirmed by the investigation team using real-time data. Of the known pressures in the various sands, this pressure best matched the M56A sand at 17,788 ft.

Reservoir Data

The reservoir pressure of the M56A sand was measured at 12,038 psi with the Schlumberger Modular Formation Dynamics Tester (MDT) logging tool. This pressure is equivalent to a 13.1 ppg mud weight, using subsea measurements as the depth reference.

The hydrocarbons in the M56A sand could either be oil or gas. The sonic log signature of the M56A sand was indicative of oil-bearing sands. However, based on the M56A position directly above the boundary of the thermogenic front, it could be gas. Performing the calculation using oil rather than gas would not change the conclusion of the hydrostatic pressure analysis.

The equivalent densities of the sands measured are:

- 14.1 ppg for M57C (measured by Geotap®).
- 13.1 ppg for M56A (measured by MDT).
- 12.6 ppg for M56E (measured by MDT).

Fluids in Wellbore

The fluids used for the calculations are:

- 8.6 ppg seawater in the drill string.
- 14.17 ppg synthetic oil-based mud in the wellbore.
- 19 bbls of in-flow fluid in the wellbore.

Witness accounts indicated that in preparation for the negative-pressure test on *Deepwater Horizon*, approximately 15 bbls of seawater were bled from the drill pipe, which was substantially above the compressibility of the system. Including seawater compressibility, approximately 3.5 bbls should have been bled to remove pressure from the well. (Refer to *Appendix R. Fluid Compressibility Calculations*.) Therefore, the investigation team concludes that this additional fluid was in-flow fluid. According to witness accounts, an additional 3 bbls to 4 bbls was bled from the kill line, which gives an estimated total in-flow volume of 19 bbls.

The in-flow fluid is assumed by the investigators to be hydrocarbons with an estimated density of 5.18 ppg at 239°F at 12,000 psi.

Note: Illustrations used in the following discussion show a sharp interface between different fluids in the well; this was done for simplicity of illustration. In reality, there would be varying degrees of fluid mixing at each interface.

After the volume was bled, the drill pipe pressure increased to 1,400 psi. *Figure 5* shows the expected position of fluids, assuming in-flow through the annulus cement barrier, through the shoe track barriers and into the production casing.

Using the 19 bbls total bleed volume, the in-flow was calculated to occupy the 7 in. casing up to 17,558 ft. The top of the 14.17 ppg mud in the drill pipe was calculated at 7,200 ft. using the 15 bbls volume bled from the drill pipe. The remainder of the drill pipe column was 8.6 ppg seawater.

Assuming the fluids configuration shown in *Figure 5*, the resulting hydrostatic pressure at 18,304 ft. is:

$$1,400 + (7,200 \times 8.6 + [17,558 - 7,200] \times 14.17 + [18,304 - 17,558] \times 5.18) \times 0.052 = 12,453 \text{ psi}$$

which corresponds to an equivalent density of:

$$\frac{12,453}{0.052 \times 18,308} = 13.08 \text{ ppg}$$

The calculated equivalent density of 13.08 ppg best matches the M56A sand.

However, some witness accounts suggested that the total volume bled back could have been more than 19 bbls. If an in-flow of more than 19 bbls occurred, the calculated shut-in pressure would be higher and therefore better match the M56A sand.

Calculations were also made for the casing hanger seal assembly path, but a match could not be made. However, using hydrostatic calculation alone, flow through the casing hanger seal assembly could not be ruled out because of the uncertainties associated with parameters affecting pressure on the assembly, such as bleed volume uncertainty, fluid density complications with the 16 ppg spacer below the BOP and weight gradients within that spacer caused by mixing at the seawater interface.

Conclusions

The 1,400 psi drill pipe pressure observed during the negative-pressure test best matched communication with the M56A sand through the annulus cement barrier and shoe track barriers. Hydrostatic pressure calculations alone were not sufficient to conclusively determine that this was the failure mode that allowed flow to the surface. Uncertainty with fluid density in the annulus, inconsistent bleed volumes from witness accounts and the presence of other sand stringers with unknown pressure were outstanding unresolved variables. Additional analysis was performed to further assess the most likely flow path and is discussed below.

Dynamic Modeling of Drill Pipe Pressure Response

The investigation included preparation of an MC 252 well flow simulation for both scenarios using the OLGA® well flow model. Outputs for each simulation were compared to real-time data and witness accounts. The scenario for hydrocarbon flow through the annulus cement barrier and shoe track barriers was validated; the scenario for flow through the casing hanger seal assembly could not be modeled.

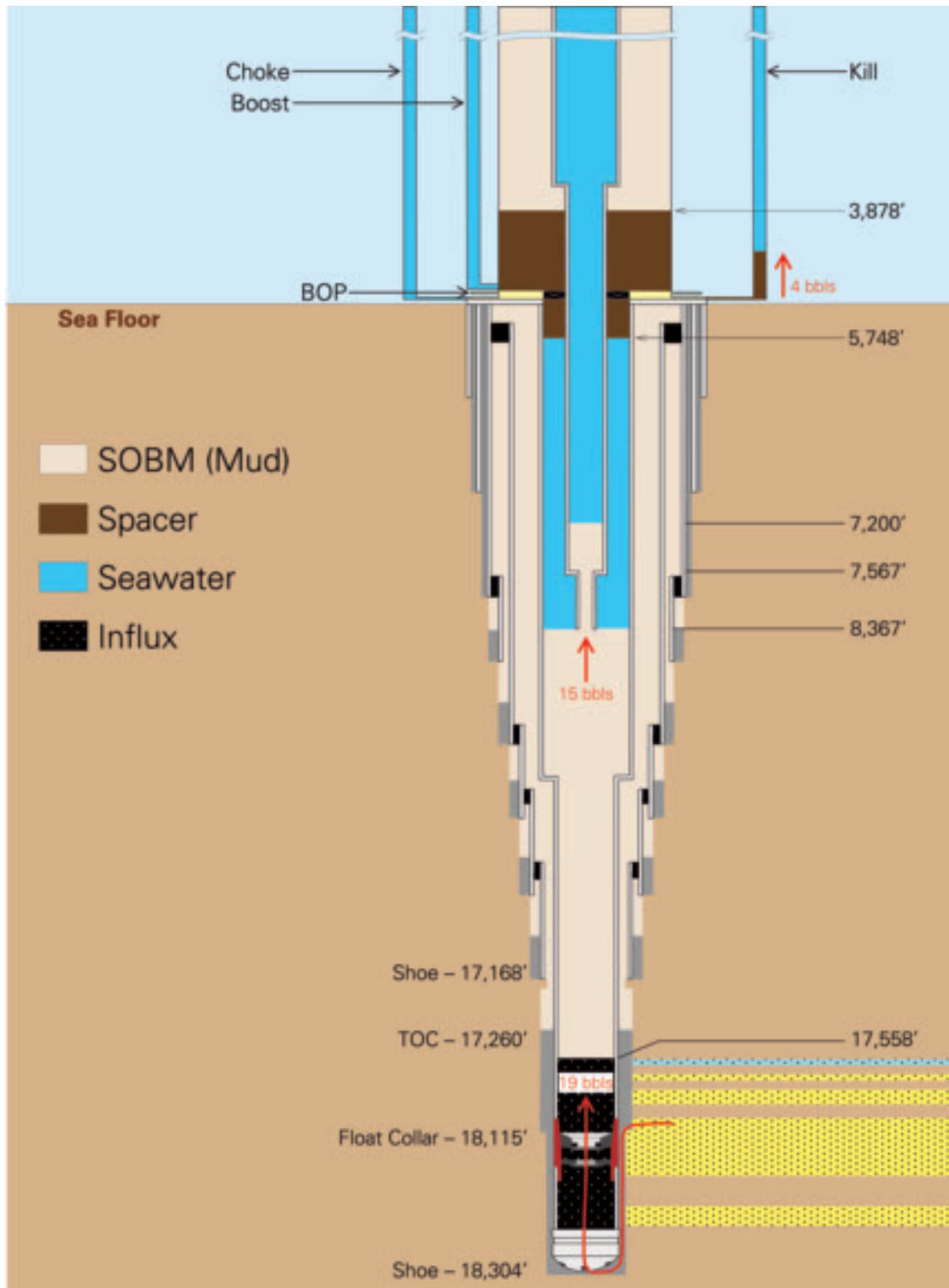


Figure 5. Mud Displacement Caused by In-flow Through the Shoe Track Barriers at Approximately 18:00 Hours.

Real-time Data and Witness Accounts of Increasing Pressure During the Sheen Test

Figure 6 shows the pressure response on the drill pipe from 21:00 hours to 21:50 hours correlated to mud pump strokes per minute (spm).

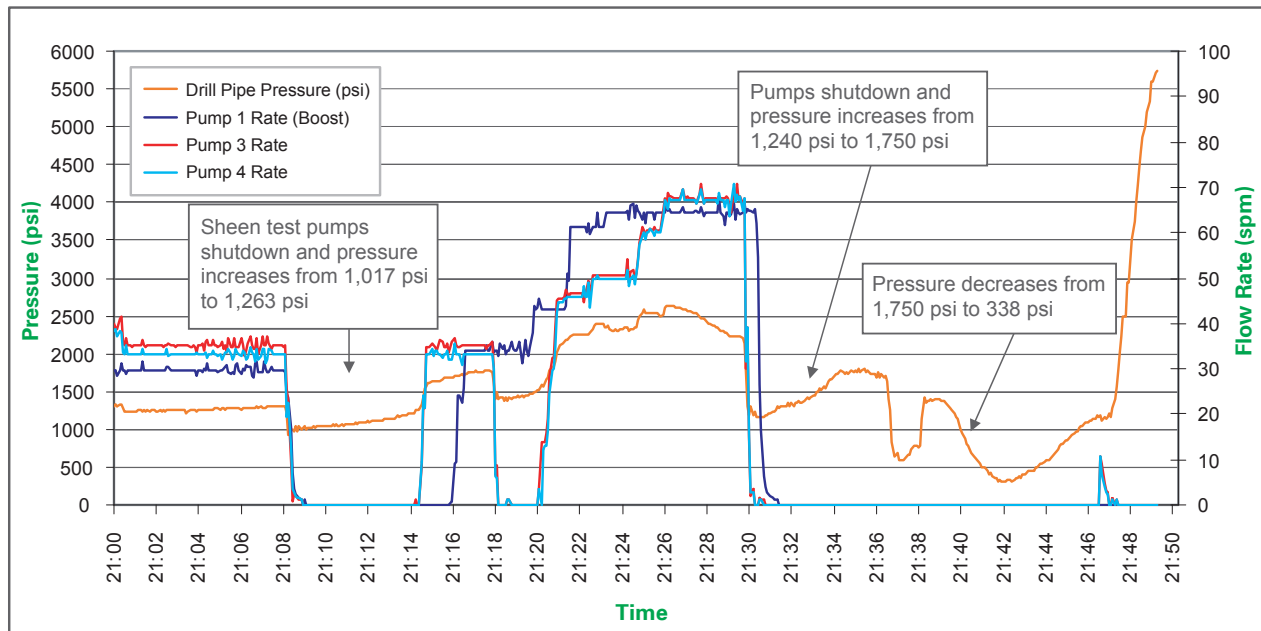


Figure 6. Drill Pipe Pressure Real-time Data from 21:00 Hours to 21:50 Hours.

At 21:08 hours, the spacer reached the top of the riser, and the mud pumps were shut down to conduct a static sheen test before commencing the displacement of the spacer overboard. From 21:08 hours to 21:14 hours, the period during which the mud pumps were shut down, the drill pipe pressure increased from 1,017 psi to 1,263 psi. The investigation team concluded that the pressure increase was probably caused by an increase in hydrostatic pressure.

Figure 7 and Figure 8 illustrate the two scenarios considered for flow from the formation into the wellbore: through the shoe track and through the casing hanger seal assembly, respectively. Evaluation of these scenarios indicates that the pressure increase in the drill pipe was caused by flow through the shoe track, as described below.

Figure 7 illustrates flow through the shoe track displacing the 14.17 ppg mud past the bottom of the drill pipe and up the annulus around the drill pipe. Each barrel of 14.17 ppg mud that filled this annulus above the bottom of the drill pipe displaced a lighter fluid, increasing hydrostatic head. At the same time, a 16 ppg spacer was displaced out of the riser, reducing the hydrostatic pressure generated by the fluid column in the riser. As stated earlier, each barrel of fluid (assuming the same fluid) in the annular space between the 3 1/2 in. drill pipe and the production casing would generate approximately 5.6 times more hydrostatic pressure than a barrel of fluid in the riser annulus.

Therefore, it could be concluded that the pressure increase generated by the 14.17 ppg mud entering the (smaller) annulus at the bottom of the drill pipe would more than offset the pressure reduction caused by 16 ppg spacer exiting the riser annulus, where the annulus cross section is larger.

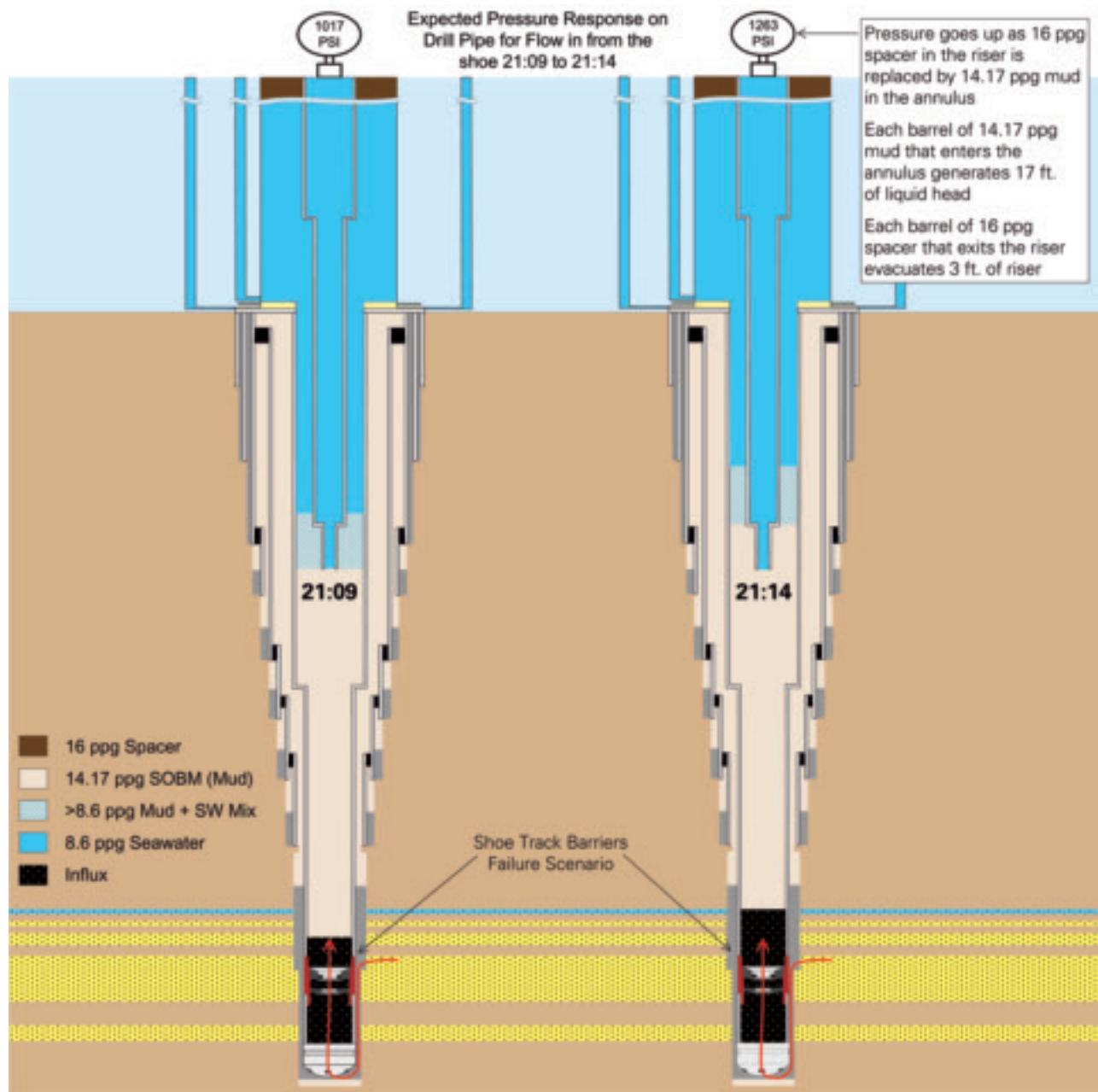


Figure 7. Model Predictions of Hydrostatic Pressure that Could Be Generated by In-flow Through the Shoe Track Barriers from 21:09 Hours to 21:14 Hours.

Figure 8 describes the effect on hydrostatic pressure if flow had been through the casing hanger seal assembly. Flow through the seal assembly would displace 16 ppg spacer out of the riser and replace it with 14.17 ppg mud at the bottom of the riser. The net effect would be a pressure decrease on the drill pipe, which is not supported by the real-time data.

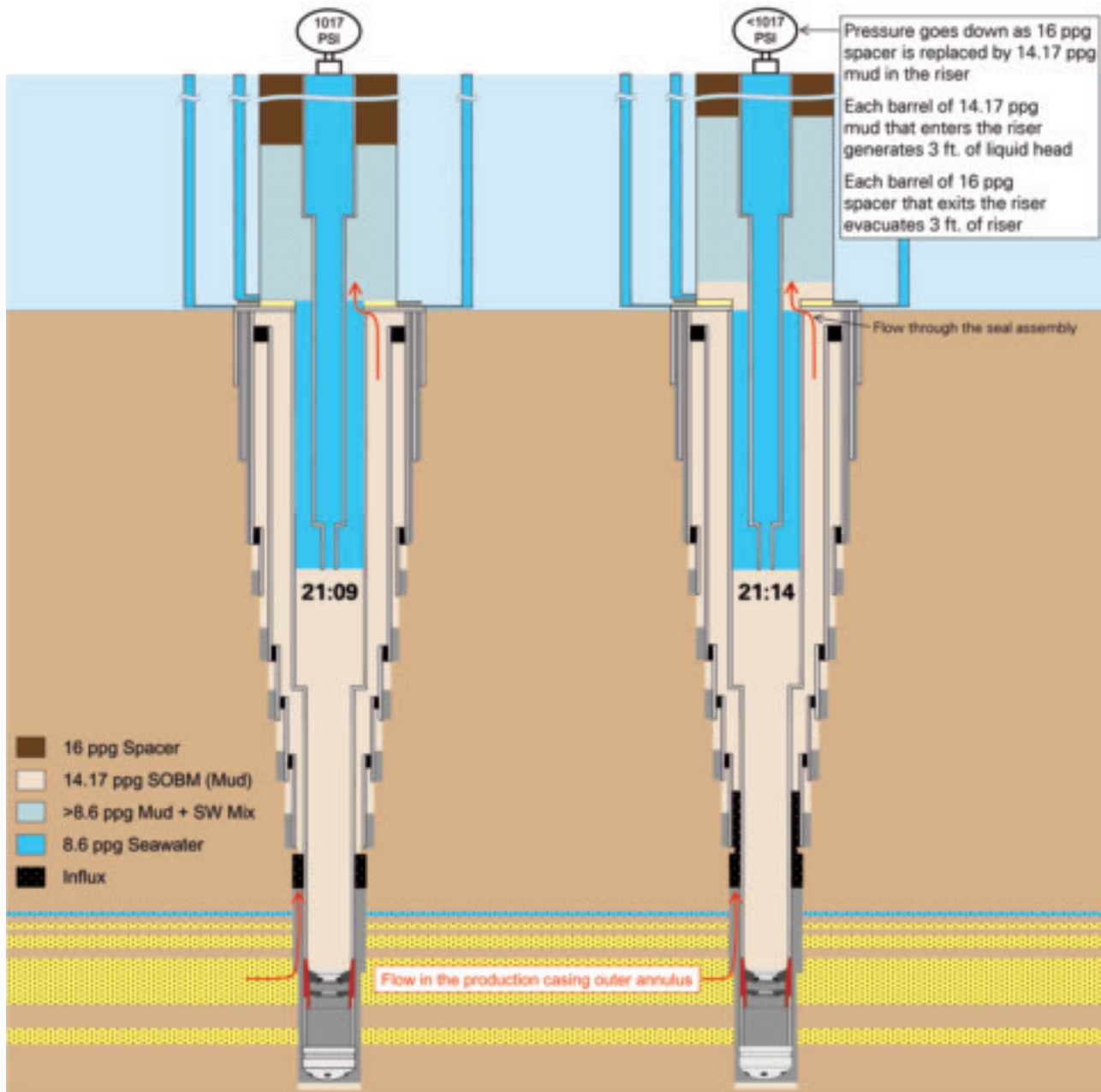


Figure 8. Model Predictions of Hydrostatic Pressure that Could Be Generated by In-flow Through the Casing Hanger Seal Assembly Barrier from 21:09 Hours to 21:14 Hours.

The Pressure Response from 21:31 Hours to 21:42 Hours

The 16 ppg spacer is believed to have been fully displaced out of the well by 21:30 hours. The mud pumps were shut down at 21:31 hours. From 21:31 hours to 21:34 hours, the pressure on the drill pipe increased from 1,240 psi to 1,750 psi. The investigation team concluded that the rig crew did not close the BOP at this time, and the pressure increase was primarily created by a hydrostatic effect due to in-flow through the shoe track barriers and up the production casing.

Figure 9(A) and *Figure 9(B)* illustrate how hydrocarbon in-flow through the shoe track barriers from 21:31 hours to 21:34 hours would have displaced 14.17 ppg mud above the bottom of the drill pipe, creating an increase in hydrostatic pressure as a lower density fluid of mixed seawater and mud was displaced out of the riser.

By 21:42 hours, the drill pipe pressure dropped to 338 psi. As shown in *Figure 9(C)*, lower density hydrocarbons migrated farther up the wellbore and above the bottom of the drill pipe. The 14.17 ppg mud from the bottom of the production casing was then fully displaced into the riser, and lower density hydrocarbons had entered the riser above the BOP.

After 21:42 hours, the pressure began to increase on the drill pipe. The investigation team believes that the BOP had been activated and started to restrict flow past the drill pipe, thus creating backpressure in the drill pipe.

As seen in *Figure 6*, between 21:36 hours and 21:38 hours, drill pipe pressure fluctuated rapidly. The investigation team believes that this was caused by a bleed off of pressure at the surface, possibly when the rig crew was investigating what they described as 'differential pressure.'

Results of Macondo Well Static Kill, August 4, 2010

The Macondo well blowout was stopped by attaching a capping stack and shutting in the well. Subsequently, the well was killed using a static kill procedure. This involved pumping (bull heading) 13.2 ppg mud into the BOP, down the casing and into the reservoir formation. Following this static kill procedure the well was plugged using cement pumped down the casing.

An analysis was completed on the available shut-in pressures, wellhead pressures, pump pressures, rates, volumes and possible flow paths in the wellbore. The analysis indicated that the fluids pumped went down the inside of the production casing and not down the production casing annulus. This would support the conclusion that communication with the formation was through the casing and shoe track.

Conclusions

Based on hydrostatic calculations and OLGA® well flow modeling, the hydrocarbon in-flow was most likely caused by flow through the annulus cement barrier and shoe track barriers of the well. Based on this work, alternative flow paths are possible but much less likely. The investigation team could not identify an alternative flow path that had both a plausible mechanical failure mode and could be modeled to match the accident timeline from a pressure response perspective. When this work is combined with analysis of the static well kill results and the other available evidence, in the view of the investigation team there is a compelling case for flow having been through the annulus cement barrier and shoe track barriers.

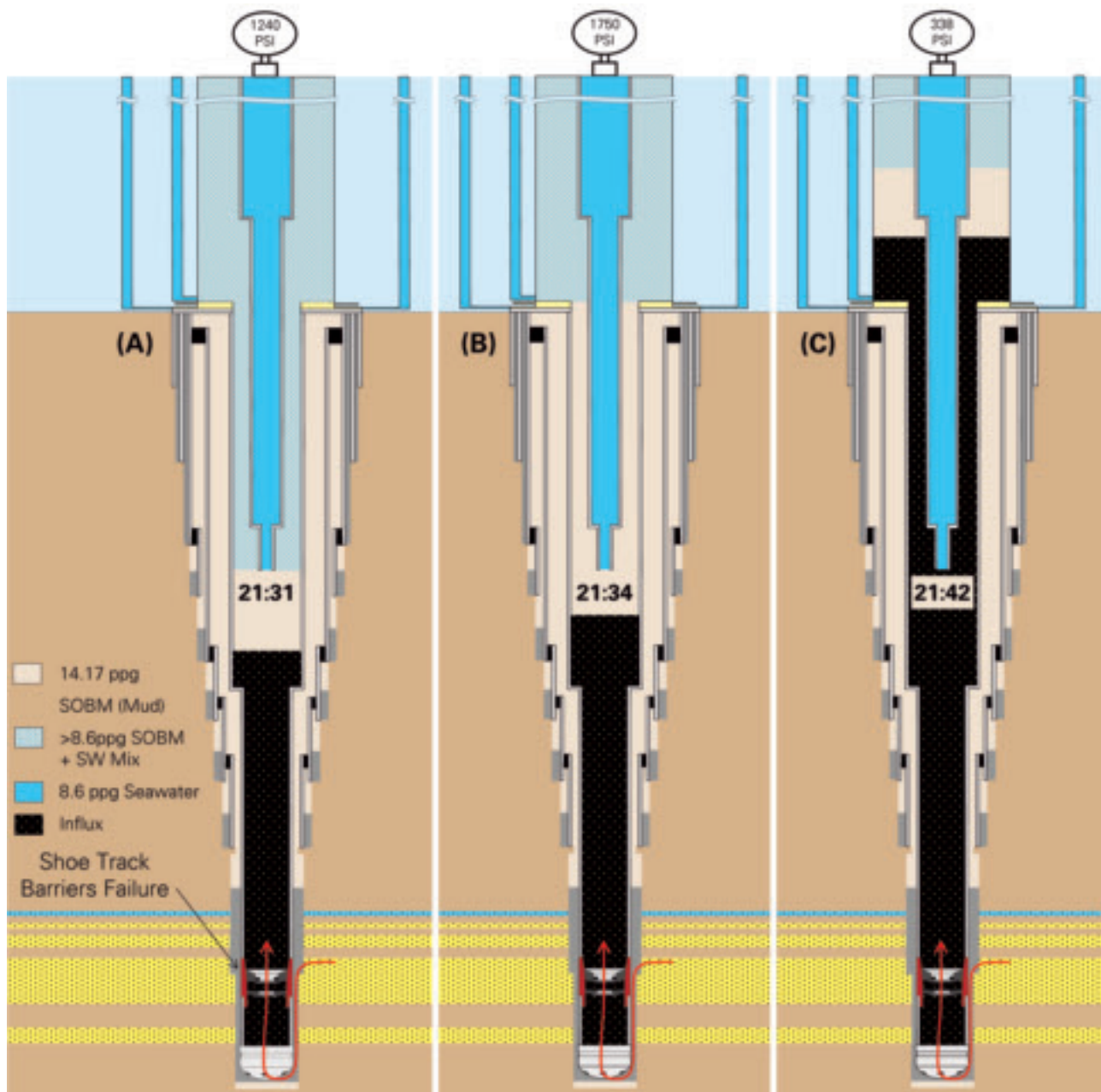


Figure 9. Model Predictions of Hydrostatic Pressure that Could Be Generated by In-flow Through the Shoe Track Barriers from 21:31 Hours to 21:42 Hours.

Appendix H. Description of the BOP Stack and Control System

Introduction

This appendix describes the major components on a blowout preventer (BOP) system and specifically provides a description of *Deepwater Horizon* BOP stack, lower marine riser package (LMRP) and control system. Applicable standards are also described.

The BOP system is safety critical, and is an integral part of the drilling system. On a subsea drilling system, the BOP system is located between the wellhead and the riser. It is designed to assist in well control and to rapidly shut in the well in the event that the well starts to flow due to an influx of formation fluids. In addition to its primary function of providing the final barrier during loss of well control, the BOP system is used for a range of routine operational tasks, such as casing pressure and formation strength tests.

Three major components of the BOP system are:

- The LMRP.
- The BOP stack.
- The control system.

The BOP system comprises individual BOPs (ram and annular) and the valves and piping (kill and choke lines) that are used to maintain control of pressure in a wellbore. The BOPs and valves are hydraulically operated. A typical BOP system for deepwater use has five to six ram-type preventers and one or two annular-type preventers:

- Variable bore rams (VBRs) are designed to close and seal around drill pipe.
- Blind shear rams (BSRs) are designed to close and seal the wellbore, shearing the drill pipe if it is present.
- Casing shear rams (CSRs) are designed to shear casing without sealing the wellbore.
- Annular preventers are positioned above ram preventers, since they are not typically rated to working pressures as high as those of the ram preventers. Annular preventers are designed to close around a wide range of tubular sizes and can seal the wellbore if no pipe is present.

Figure 1 is a schematic representation of *Deepwater Horizon* BOP system.

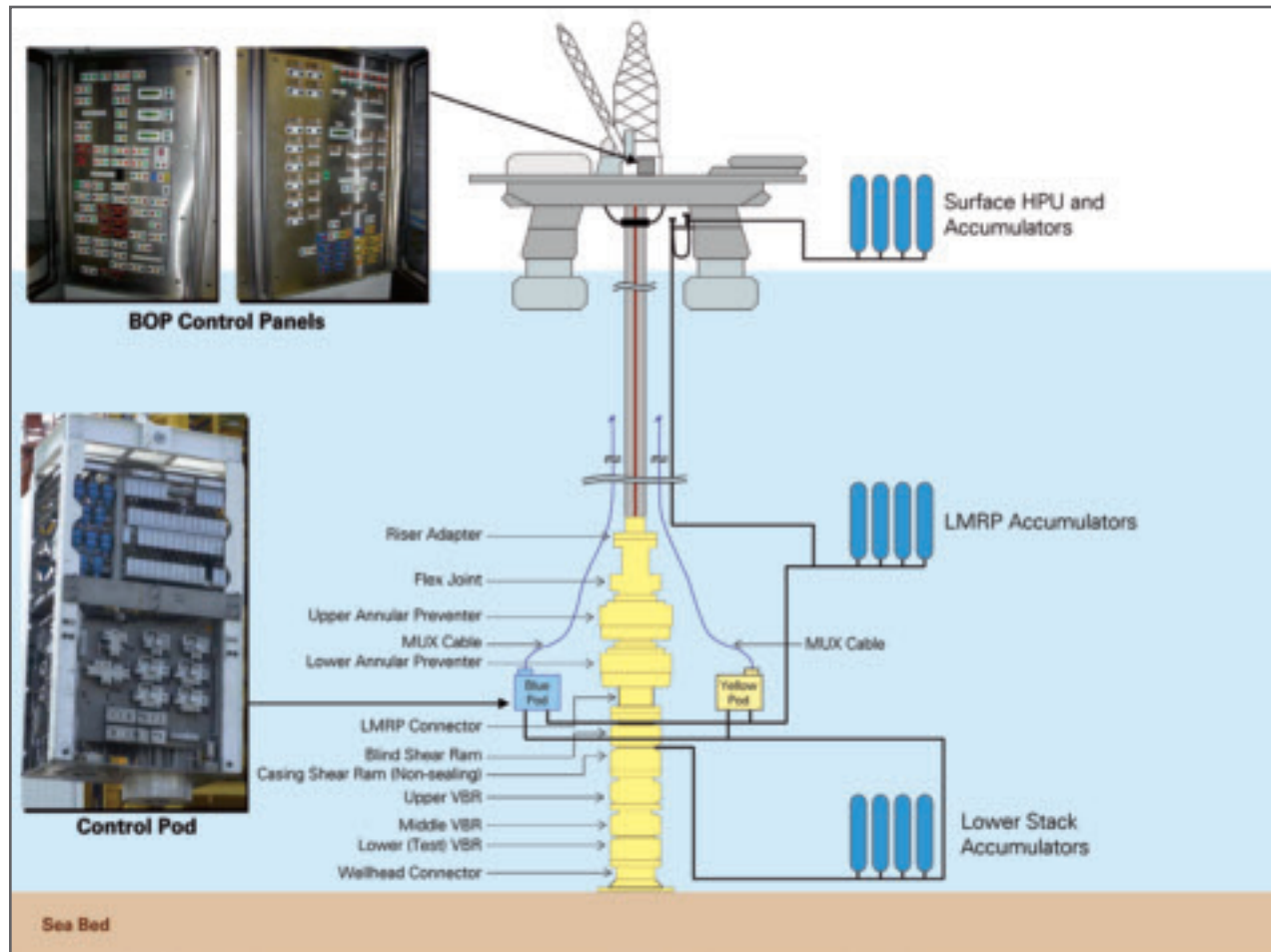


Figure 1. A Schematic Representation of Deepwater Horizon BOP System.

2 Detailed Description

As described in the Cameron *BOP Operation and Maintenance Manual*, the BOP system on *Deepwater Horizon* was a “TL BOP Guidelineless Stack, 18 3/4 in., 15,000 psi system.” Figure 2 shows a simplified diagram of the BOP and a photograph of it in the moon pool on the rig.

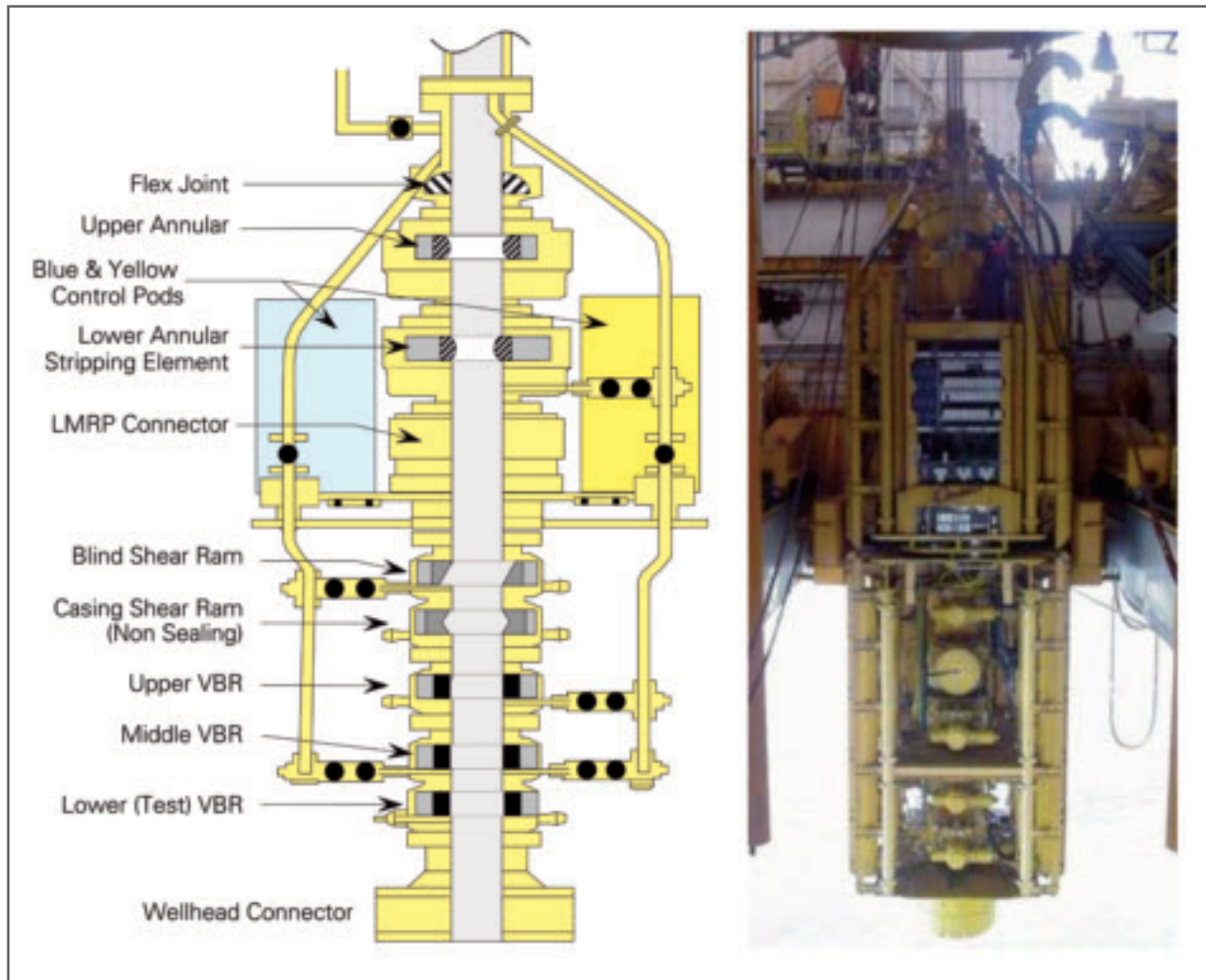


Figure 2. Diagram and Photo of *Deepwater Horizon* BOP System.

The BOP stack was attached to the wellhead with a hydraulically operated, high-pressure wellhead connector manufactured by Vetco (18 3/4 in., 15,000 psi type 'SHD-H4'). A Flexjoint™ riser adapter (manufactured by Oil States) assembly attached the LMRP to the marine drilling riser. The LMRP had a Cameron 18 3/4 in., 10,000 psi type 'HC' hydraulically-actuated connector at its lower end, giving it the ability to disconnect from the BOP stack and allowing retrieval back to surface.

2.1 LMRP Details

Figure 3 shows the major components of the LMRP. The following discussion and item numbers reference this figure.

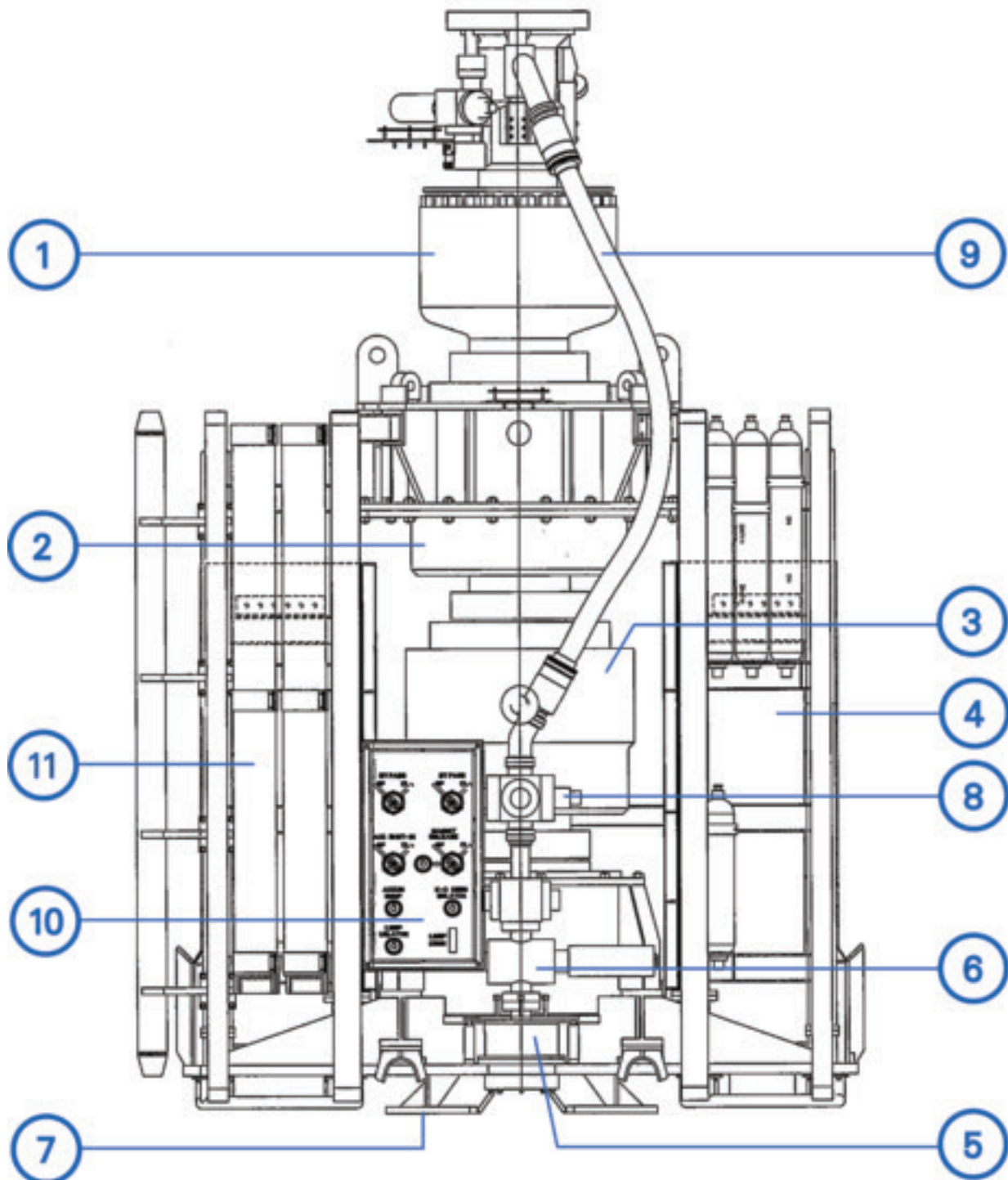


Figure 3. LMRP Assembly.

(1) Flexjoint™ Riser Adapter

The Flexjoint™ riser adapter assembly was the uppermost component in the LMRP. The adapter contained a 5,000 psi flexible joint that allowed for the deflection of the marine drilling riser from the vertical axis of the BOP stack. The Flexjoint™ device was manufactured by Oil States and had the ability to handle up to 10° of angular deflection at any heading.

The assembly also had a mud boost line port that allowed mud to be pumped into the marine drilling riser to boost cuttings back to the surface (through the marine drilling riser). The riser flange connection at the top of the adapter located immediately above the Flexjoint™ provided a load-carrying connection point between the marine drilling riser and the LMRP and provided the connection between the external service lines on the marine drilling riser and the LMRP and BOP stack. These external service lines were the choke, kill, hydraulic conduit (subsea control system hydraulic supply) and mud boost lines.

(2) Upper Annular Preventer

The upper annular preventer was a Cameron 18 3/4 in., 10,000 psi type 'DL' BOP. This annular preventer was used to seal the wellbore annulus while drill pipe and/or casing was being run through the LMRP and BOP stack. The packing element installed in the upper annular preventer was rated for 10,000 psi when closed around a pipe or 5,000 psi when closed on an open hole.

(3) Lower Annular Preventer

The lower annular preventer was a Cameron 18 3/4 in., 10,000 psi type 'DL' BOP. This annular preventer was rated for 10,000 psi when it was purchased, according to the Cameron *BOP Operation and Maintenance Manual*. At the time of the accident, the lower annular preventer was configured with a stripping packer with an element having a pressure rating of 5,000 psi when closed around drill pipe. The stripping packer was designed to allow drill pipe tool joint stripping (raising and lowering) without damaging the packer or the drill pipe tool joint. According to Cameron's documentation, the stripping packer design was tested to 5,000 psi on 5 1/2 in. and 6 5/8 in. drill pipe.

(4) Control Pods

Two Cameron 'Mark II' electro-hydraulic multiplex (MUX) control pods provided control function and communication between the subsea LMRP and BOP stack components and the surface control system. These pods were designated as the blue pod and the yellow pod. A spare pod that was held on the rig was designated as the white pod.

(5) Choke and Kill Connectors

Cameron 3 1/16 in., 15,000 psi choke and kill connectors were hydraulically operated connectors. These connectors provided high-pressure connections between the choke and kill lines on the LMRP and the BOP stack.

(6) Choke and Kill Line Isolation Valves

Two Cameron 3 1/16 in., 15,000 psi gate valves with fail safe 'open' hydraulic operators were used to isolate the choke and kill lines.

(7) LMRP Connector

A Cameron 18 3/4 in., 10,000 psi type 'HC' connector was used to provide a connection between the bottom of the LMRP and the top of the BOP stack. The hydraulically-actuated connector permitted separation of the marine drilling riser from the BOP stack for retrieval of the marine drilling riser and the LMRP. This allowed the BOP control pods to be retrieved to surface for repair, while leaving the BOP stack shut-in on the well. This connector also allowed the marine drilling riser and the LMRP to be disconnected from the BOP stack in the event of loss of rig dynamic-position station keeping (i.e., rig drift-off or drive-off). This type of disconnect is referred to as an emergency disconnect sequence (EDS). This connector had the ability to disconnect from the BOP stack with up to a 10° vertical misalignment.

(8) Gas Bleed Valves

The gas bleed valves were Cameron dual body gate valves, 3 1/16 in., 15,000 psi with fail safe close hydraulic operators. The purpose of these valves was to allow residual gas to be circulated from the LMRP and BOP stack after a well kill operation.

(9) Choke and Kill Flexible Lines

Two flexible steel choke and kill lines, 3 1/16 in. inner diameter (ID), 15,000 psi provided flexibility in the LMRP choke and kill system around the Flexjoint™ riser adapter.

(10) ROV Interface Control Panel

The remotely operated vehicle (ROV) interface control panel allowed select functions on the LMRP to be operated using ROV intervention.

(11) LMRP Hydraulic Accumulators

Four 60-gallon, 5,000 psi accumulator bottles supplemented the hydraulic fluid volume and pressure being supplied to the subsea hydraulic control pods' BOP system through the rigid conduit line on the riser from the surface pump and accumulator system.

2.2 BOP Stack Details

The BOP stack comprises high-pressure (15,000 psi) components. *Figure 4* shows the arrangement of the BOP stack and its major components. The following discussion and item numbers reference this figure.

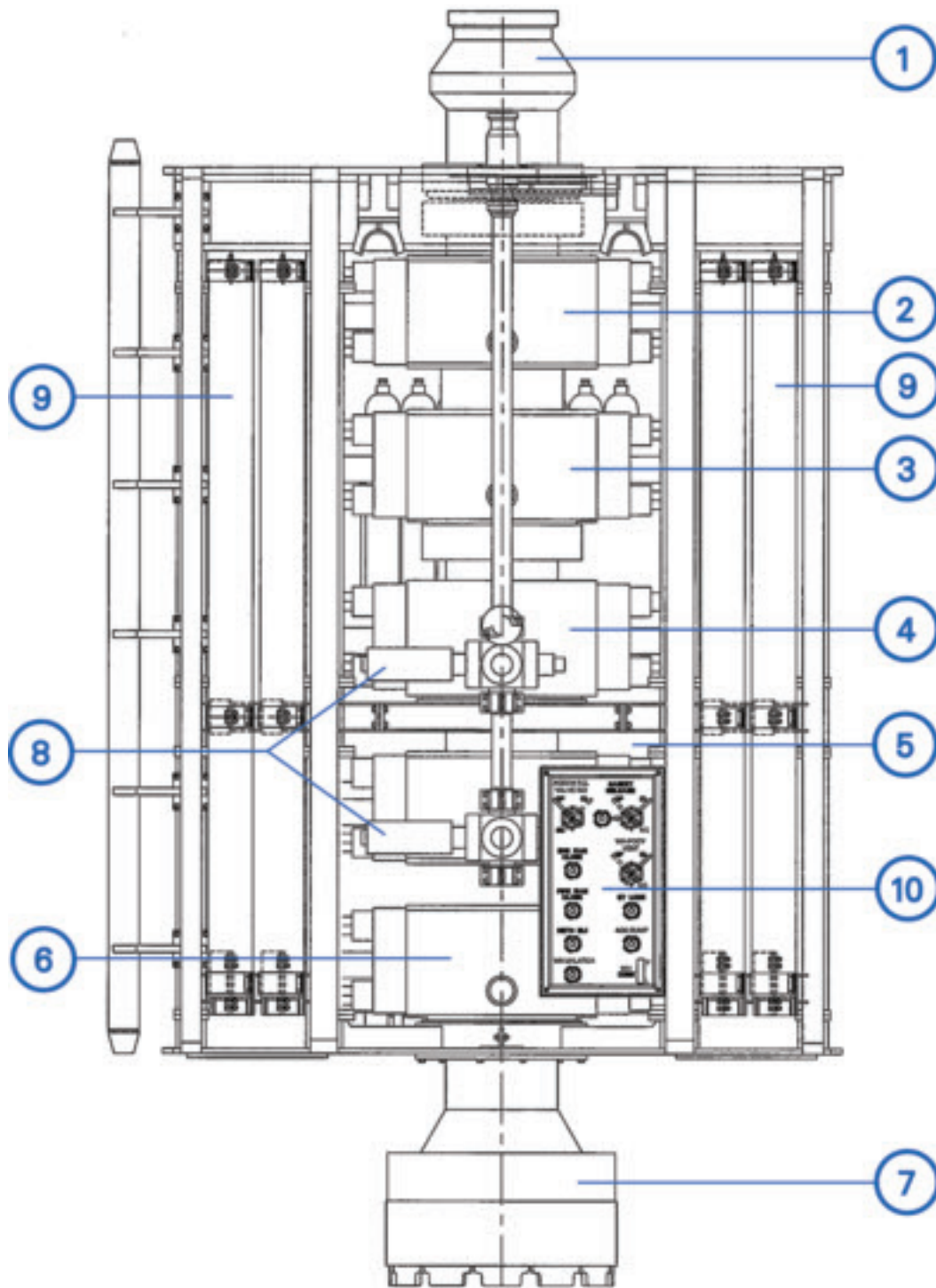


Figure 4. BOP Stack.

(1) LMRP Mandrel

The LMRP mandrel was an 18 3/4 in., 10,000 psi mandrel with a top hub profile that is suitable for connection with the LMRP connector (Cameron hub). The mandrel provided a full-bore, high-pressure connection between the BOP stack and the LMRP.

(2) Blind Shear Ram

The BSR was a Cameron 18 3/4 in., 15,000 psi type 'TL' double ram preventer. The upper cavity of this ram preventer was fitted with Cameron type 'shearing blind rams' that were used to cut the drill pipe (if present) and seal the wellbore. This preventer could be actuated in two modes: under 3,000 psi closing pressure (blind shear), or 4,000 psi closing pressure (high-pressure blind shear). The upper cavity was fitted with Cameron standard ram bonnets (which contained the actuating pistons) and 'ST' locks (which could be used to hold the closed rams in position).

(3) Casing Shear Ram

The lower cavity of this preventer was fitted with Cameron 'Super Shear' rams. These rams were capable of cutting drill pipe, casing and tool joints, but they could not seal the wellbore. The cavity was fitted with Cameron 'Super Shear' bonnets that could not be locked after they were closed.

(4) Upper Pipe Ram

The upper pipe ram was a Cameron 18 3/4 in., 15,000 psi type 'TL' single ram preventer. This ram preventer was fitted with Cameron VBRs that were capable of closing and sealing on tubulars that had an outer diameter (OD) between 3 1/2 in. and 6 5/8 in., and it was fitted with Cameron 'standard' ram bonnets and ST locks.

(5) Middle Pipe Ram

The middle pipe ram was a Cameron 18 3/4 in., 15,000 psi type 'TL' double ram preventer. The upper cavity of this ram preventer was fitted with Cameron VBRs that were capable of closing and sealing tubulars that had an OD between 3 1/2 in. and 6 5/8 in. and it was fitted with Cameron 'standard' ram bonnets and ST locks.

(6) Lower Pipe Ram

The lower cavity of this preventer was fitted with inverted Cameron VBRs that were capable of closing and sealing on tubulars that had an OD between 3 1/2 in. and 6 5/8 in. and sealing the wellbore pressure from above the ram. This pipe ram was referred to as the 'test ram,' and it was fitted with Cameron 'standard' ram bonnets and ST locks.

(7) Wellhead Connector

The wellhead connector was a Vetco 18 3/4 in., 15,000 psi, type 'SHD-H4' wellhead connector. This hydraulically-actuated connector was used to connect the BOP stack to the top of the 18 3/4 in., 15,000 psi subsea wellhead housing.

(8) Choke and Kill Line Valves

The choke and kill line valves consisted of four Cameron dual body gate valves that were 3 1/16 in., 15,000 psi with fail safe 'close' hydraulic operators. These valve assemblies were used to isolate the choke and kill line piping connections to the BOP rams.

(9) BOP Stack Hydraulic Accumulators

Eight 80-gallon, 5,000 psi accumulators on the BOP stack were dedicated to the three emergency operations (autoshear, automatic mode function [AMF] and EDS) of the BSRs and the CSRs. (Refer to Figure 1.) The accumulator bottles were also used for the normal closing operation of the high-pressure BSRs and the high-pressure CSRs. These accumulators stored hydraulic fluid at 5,000 psi and received their supply from the rigid conduit line through subsea pods that were mounted on the LMRP. The maximum operating pressure for the high-pressure BSRs and high-pressure CSRs was reduced to 4,000 psi by manually-set hydraulic regulators.

(10) ROV Interface Control Panel

The ROV interface control panel was located on the BOP system to allow ROV intervention to operate select BOP functions.

3 Electro-hydraulic Control System

The operation of *Deepwater Horizon* BOP system was controlled by a Cameron 'Mark II' electro-hydraulic MUX control system.

The BOP system's annular preventers, ram preventers, connectors and valves were hydraulically actuated. The hydraulic power was delivered by a hydraulic power unit (HPU) located on the rig. The HPU charged the surface accumulators to 5,000 psi and provided hydraulic fluid through a 3 1/2 in. OD rigid conduit line and an auxiliary 1 in. OD hot line hose to the BOP.

The rigid conduit line was the primary hydraulic fluid supply. The hot line supplied hydraulic fluid to the BOP control system while the BOP system was being deployed to, or retrieved from, the sea bed. The rigid conduit line and the hot line terminated at the conduit valve package (CVP) on the LMRP. From the CVP, the hydraulic fluid was directed to either the yellow or the blue pod (depending on which pod was selected by the operator on the rig) to be the active pod. Only one pod was required at any given time for the BOP hydraulic system to function, and that pod was the only one that received hydraulic fluid supply. However, the other (redundant) pod received electrical commands and energized the solenoid valves simultaneously with the active pod.

The control system primarily consisted of two control stations on the rig: the driller's control panel (located in the driller's cabin), and the toolpusher's control panel (located on the bridge). Each control panel contained two programmable logic controllers (PLCs) on two independent control networks (A and B) and two independent power distribution networks (A and B). The control and power networks supplied power and communications to the surface equipment and to the two subsea electronic module (SEM) housings located in each pod. The SEM received commands from the surface system to energize or de-energize the appropriate solenoid valves. Each SEM housing contained two independent PLCs, which were designated as SEM A and SEM B.

Figure 5 shows the major components contained within the SEM housing:

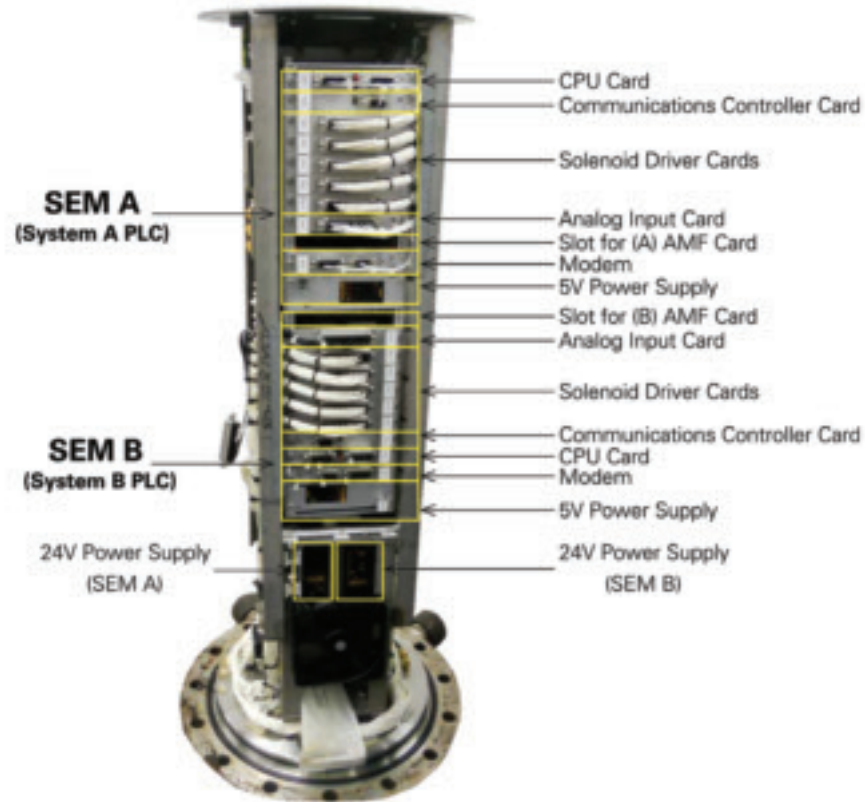


Figure 5. SEM Housing Located in Each Pod.
(Typical Cameron 'Mark I' SEM [not from *Deepwater Horizon*].)

Full duplex modems (using a Cameron proprietary custom protocol) carried communication from the surface to the SEMs. Two independent MUX cables (designated yellow and blue, corresponding to the two pods) carried power and communications subsea.

Both SEMs contained:

- Two power supplies (converting 230-volt AC power from surface to 24-volt DC and 5-volt DC).
- A modem.
- A central processing unit.
- Solenoid driver modules.
- An analog input module.
- An automated mode function (AMF) card.
- Batteries (27-volt DC and 9-volt DC) used for powering the AMF in the event that the surface power supply failed.

The operator selected the pod and SEM that would use the surface hydraulic supply to operate the BOP system. If the operator selected 'blue pod—SEM A,' the blue pod would have had hydraulic supply from the surface, and SEM A would have been selected (within the blue pod's SEM housing) to provide the operator with the information displayed on the control panels. The event logger on the rig continuously recorded electronic data from all four SEMs and all surface panels.

The selected SEM operated the solenoid valves, which in turn provided hydraulic pilot signals to the various hydraulic control valves located in the subsea control pod. Pilot signals acted as a hydraulic switch to operate larger hydraulic components.

Each solenoid contained two coils (A and B). As each function was activated from the surface, a command was issued to both the yellow and the blue pods, then to both SEMs in each pod. Four solenoid coils were energized for every valve operated.

When a solenoid valve was energized in the active pod, the valve opened and allowed the hydraulic fluid supply to enter the specified hydraulic circuit to operate the selected equipment on the BOP system.

The SEM also had the ability to monitor and transmit any measured data from instruments within the pod and on the BOP system (e.g., hydraulic control pressures, hydrostatic pressure, choke and kill line pressure, wellbore pressure and inclinometer measurements) to surface. This information assisted the operator in making decisions regarding BOP system operation.

4 Applicable Industry Standards

Deepwater Horizon BOP stack, LMRP and control system components were manufactured, assembled and factory-acceptance tested from 2000–2001. The stack assembly, along with the BOP control system, was installed and commissioned aboard *Deepwater Horizon* in 2001, and it remained with the rig for its entire working life.

The pressure containing and controlling components (i.e., ram preventers, annular preventers, connectors and choke and kill valves) were designed, manufactured and factory tested in accordance with the applicable requirements of the American Petroleum Institute (API) *Spec 16* and API *Spec 6A*. These API standards also included the requirements of the National Association of Corrosion Engineers (NACE) *MR 0175* (requirements for operating in a sour gas environment), the American Society of Mechanical Engineers (ASME) standards (for welding procedure qualification and welder qualification) and various other industry standards.

Industry standards did not exist for some components of the BOP system. In these cases, the component designer and manufacturer defined standards to which the components were designed, manufactured and factory tested prior to delivery.

The testing required by API standards for BOP components and gate valves was static testing, as opposed to dynamic testing (i.e., simulating a well flowing condition).

The arrangement of the LMRP and BOP stack components was also consistent with the *Code of Federal Regulations* (CFR) for oil and gas drilling in the U.S. Offshore Continental Shelf. (Refer to *30 CFR, Chapter II, Subpart D*.)

5 Applicable BP Standards

Table 1 shows a comparison between *Deepwater Horizon* BOP stack configuration and BP's *Engineering Technical Practice (ETP) GP 10-10, Well Control Engineering*.

Table 1. Comparison Between *Deepwater Horizon* BOP Stack Configuration and BP's *ETP GP 10-10*.

Section	Excerpt from BP's ETP (GP 10-10)	<i>Deepwater Horizon</i> BOP Stack Configuration
7.5.2	<p>As arranged from top to bottom, the minimum BOP configuration shall be required for wells where a wellhead pressure of over 5,000 psi is possible, is:</p> <ul style="list-style-type: none"> Two annular preventers, one of which is retrievable on lower marine riser package. Four ram type preventers. Outlets for choke and kill lines. <p>There shall be a minimum of three inlets/outlets. Where there are four inlets/outlets, one shall be below the lowermost ram. Where there are three inlets/outlets, the single kill or choke line connection shall not be below the lowermost ram.</p>	<p><i>Deepwater Horizon</i> BOP system had two annular preventers on the retrievable LMRP and five ram type preventers on the BOP stack. Two of the ram type preventers were not configured for sealing wellbore pressure: the casing shear rams did not seal, and the lower pipe rams had a test ram configuration that would only seal pressure from above the ram. A BP dispensation was approved in 2004 to "convert bottom pipe ram on the <i>Deepwater Horizon</i> BOP to a test ram."</p>
7.5.3	<p>A sealing shear ram shall be required. The limitations of its shearing capacity should be known and understood, and a documented risk assessment shall be in place to address any such limitations.</p>	<p>A sealing shear ram (BSR) was included in the stack. The BSR capability was verified in the yard during rig commissioning when 5 1/2 in., 21.9 ppf pipe was sheared at 2,900 psi. The BSR also successfully sheared 6 5/8 in. drill pipe when an EDS function was executed in June 2003.</p>
7.5.5	<p>The BOP stack shall contain a pipe ram that can close on every size of drill pipe and tubing that comprises a significant length of the total string. Where tubular accessories (e.g., cables, clamps, screens, etc.) may compromise a shear ram or pipe ram seal, then appropriate procedures and contingencies shall be in place to mitigate this risk.</p>	<p><i>Deepwater Horizon</i> BOP stack had two VBR-equipped ram preventers that were capable of closing on 3 1/2" to 6 5/8" OD pipe and sealing wellbore pressure.</p>
7.5.6	<p>The lowermost ram shall be preserved as a master component and only used to close in the well when no other ram is available for this purpose.</p>	<p><i>Deepwater Horizon</i> BOP stack had the lowermost ram converted to a test ram. The middle pipe ram was capable of satisfying this requirement.</p>
7.5.7	<p>Ram type preventers shall have remotely or automatically operated ram lock systems fitted.</p>	<p><i>Deepwater Horizon</i> BOP stack was equipped with remotely operated ram locks on the BSRs, pipe rams and test ram. The casing shear ram was not equipped with a ram lock.</p>

